NiSource Energy
Distribution Group

March 1, 2002

SENT VIA E-MAIL

Chairman William D. McCarty
Indiana Utility Regulatory Commission
302 W. Washington Street
Room E306
Indianapolis, IN 46204

Re: Advanced Notice of Proposed Rulemaking on Distributed Resources

Dear Chairman McCarty:

In response to the Indiana Utility Regulatory Commission's ("IURC" or "Commission") Advanced Notice of Proposed Rulemaking ("ANOPR") on Distributed Resources, please find the attached joint response from the Northern Indiana Public Service Company ("NIPSCO") and NiSource Inc.

NIPSCO and NiSource appreciate the opportunity to respond to this preliminary discussion, and we hope that this open conversation will continue to recognize many of the important issues surrounding Distributed Generation ("DG"). As we discuss in the attached responses, both NIPSCO and NiSource believe there are ways to provide a framework to all parties involved in order make DG a worthwhile endeavor as recognized in your transmittal letter dated January 25, 2002.

NIPSCO and NiSource also appreciate the Commission's recognition that this rulemaking process may be protracted. We look forward to participating in this process.

As part of the Commission's request for comment, it stated that it wanted parties to add any new areas of comment beyond the questions listed within the white paper. NIPSCO and NiSource have two other areas of comment, and they are listed as questions (t.) and (u.) in the attached responses.

Sincerely,

/s/ Timothy R. Caister

Timothy R. Caister
Regulatory & Government Policy

Enclosures

RESPONSES OF
NORTHERN INDIANA PUBLIC SERVICE COMPANY
&
NISOURCE INC.
TO IURC JANUARY 25, 2002, DISTRIBUTED GENERATION WHITE PAPER

a. Please provide a definition of distributed generation, including engineering characteristics and unit size. Should the definition differ depending on the customer class?

NIPSCO and NiSource Inc. submit that Distributed Generation ("DG") is generation primarily designed and sized for, and placed near to, the load center in an effort to either displace some portions of the electric requirements from the host electric distributor or meet all the entire load center's system electric requirements. The electricity produced from the DG unit may be a by-product from a system that supplies thermal, or other, products.

DG is not necessarily an Independent Power Producer ("IPP") located on the distribution system solely for the purpose of generating electricity into the wholesale or retail markets. As contemplated by the IURC's white paper, DG represents an additional benefit to the customer responsible for the facility by displacing some or all of its electric requirements. Therefore, NIPSCO and NiSource Inc. would not support a definition that would include generating facilities that do not benefit the customer in this manner.

In addition, DG should not be based on or differ according to an arbitrary MWh/KWh level or customer class, but it is better addressed by a "matching" concept discussed above. DG simply is generation "matched" to a load center that is physically located near it. However, there are some areas where addressing DG by size is necessary, and these are addressed below in questions (e), (i), and (r).

There are other matters outside of the above definition that could encompass DG. For example, VAR support, substation support, load following, regulation, and other FERC Order Nos. 888 and 889 ancillary services represent services that could provide benefits to both the local electric utility and the customer.

Lastly, NIPSCO and NiSource Inc. believe it is important that the definition incorporate recognition for combined heat and power ("CHP") resources. In those instances in which the generation system uses recovered waste heat to provide other energy products (*e.g.* process water, steam, heat and/or cooling), the facility is properly defined as CHP.

b. Assuming net metering as the first step in a DG rulemaking, what are the benefits for customers with net metering and what are the possible negative effects?

NIPSCO and NiSource understand that the Commission has assumed net metering as the first step; however, it is necessary to mention that net metering may not be the most appropriate first step in DG rulemaking. The most appropriate first issue is likely stranded costs. Stranded costs, as highlighted in the IURC's white paper, are a growing concern, and NIPSCO and NiSource believe there are ways to alleviate these concerns, and those are discussed below in questions relating to stranded costs.

In an effort to assist the Commission in visualizing the DG and utility regulatory process, NIPSCO and NiSource have attached Exhibit 1. This exhibit provides a very simple diagram of the DG process. It is not intended to cover resolution of the issues, or even cover all of the issues, but NIPSCO and NiSource hope that it illustrates the necessary steps in this rulemaking process.

A further threshold concern with net metering is what is the net result measuring? Net metering can mean two different functions: either (1) a net result of power (*i.e.* only a "net" consumed power is measured), or (2) a billing function that measures both power in and power out and "nets" it for billing purposes. Therefore, the Commission should consider the question and define "net metering" as either (1) an economic and billing issue, or (2) an energy commodity measurement issue. If it is an energy commodity measurement issue, then two mono-directional meters are required. If the utility begins to use two mono-directional meters, this may present some cost concerns for the DG developers because the two flow values may be valued differently.

Regarding the benefits to customers, DG net metering:

- Allows for efficient utilization of a distributed generation asset because, depending upon the type (*i.e.* wind versus natural gas), the customer is able to harness efficiencies at the customer's site.
- May help deliver accurate price signals since DG is rewarded most where existing distribution system costs the most to use. If the customer is able to locate its DG facility in areas of the electric utility's distribution system that need facility support, then the customer may be able to recognize a portion of the benefit. Nonetheless, this assumes that the electric utility provides information to the public where its system could use facility support. There are concerns that detailed information should not be publicly available information, and this is addressed below in question (m).
- Provides the ability for customers to sell generation back at full tariff rate up to a "certain level," assuming the tariff structure allows it. As outlined below in the negative effects section, one bi-directional meter does not provide the customer or the utility with the corresponding energy values going into and out of the facility. However, this benefit of netting the customer's load to zero does not provide the utility with enough information.
- Provides the ability for customers to use all potential generation, not just generation needed to meet their own power requirements. However, as provided in the previous statement, the incentive to sell the generation back at full tariff rate should not be extended beyond a "certain level"; however, even beyond a

"certain level," the customer still has the ability to sell generation at an avoided cost rate or another rate that recognizes the true value of the power.

- Provides the ability for customers to bank power during billing cycle and from period to period. Please see question (c) for a discussion of the utility's perspective.
- Is a simpler concept versus trying to apply an avoided cost rate or time of generation rate.
- Is an incentive for customers to produce more of their own load when they are given a full tariff price benefit for their power up to the certain level discussed above.
- Avoids the costly process for installing new meters at the customer's location.

Regarding the negative effects to customers, DG net metering:

- Does not provide the DG customer with the proper valuation of its generation if net metering is defined as a single bi-directional meter. This is true because the ability for the meter to run backwards and "bank" a credit for the customer does not allocate the proper market price signal to the customer.
- Values all power, at all times, the same, at the full tariff rate. If it is valued the same, this does not give an accurate market signal for the value of peak versus off-peak power when customers evaluate conservation efforts at their facility.
- Distorts the value of power because the ability to bank power within billing cycles and from period to period does not provide the customers enough information to evaluate their DG projects.
- Assumes one bi-directional meter. Assuming and implementing one bi-directional meter will not provide the customer and the utility enough information because it is unable to register flows into and out of the customer as two separate values. This is important because the one net figure fails to measure the customer's load or generation growth behind the meter. Furthermore, if it is later decided that the customer needs a different metering set up, then fixed charge expenses will increase in order to install new metering.
- Increases potential for stranded costs.
- Does not solve the lack of data problem in order to properly plan DG installations and their growth.
- May cause electric system concerns because, depending on the size, placement, and time, there is a lack of information as noted above.
- Highlights a concern of who pays for the costs associated with booking and who gets the credit. Therefore, real-time pricing problems increase.

c. What kind of tariff structure can be used to deal with different amounts and sizes of DG and still make net metering practical?

As highlighted above in question (b), NIPSCO and NiSource believe there is a certain "ceiling level" above which the DG customer's generation should not be valued at full tariff rate. This level should be directly based upon the DG customer's pre-facility load in order to properly encourage the customer to design generation to meet its own load.

There is a further reason why this “ceiling level” is appropriate. If a DG customer does intend to design its generation above its historic load, then it should only realize the true value of that power beyond the “ceiling level.” The true value is not the full tariff rate, but a rate that follows the market at that time of day and year. Therefore, the excess power generated beyond the “ceiling level” should not be recognized at the full tariff rate.

The next issue then becomes how is the “ceiling level” defined? The Commission should consider the DG customer’s pre-facility load level. One consideration is setting a “ceiling level” of 110% of the customer’s level. Another consideration is to review the customer’s load profile for the last twelve months and include an analysis of its demand level and total energy consumption. In either instance, the Commission should recognize the importance of establishing a “ceiling level,” and then the importance of reviewing this level in subsequent years to make sure that the utility is not granting a greater “ceiling level” than what is appropriate.

Even after a “ceiling level” is established, the ability to grant the power generated by a DG customer up to its “ceiling level” at full tariff rate still presents a fixed cost issue. In regard to the fixed charge portion lost in granting the power at full tariff rate, the utility should recover some of its fixed costs by implementing a monthly charge for net metering. Still assuming that the DG customer is connected to the utility, this basic fee would incorporate many of the facility costs that are required for the connection, and would not ask the other customers on the utility system to compensate for the net metering. This would also present the proper price signal to the DG customer because this fixed charge portion is not related to volumetric portions of the full tariff rate. Both NIPSCO and NiSource value this suggestion. As the Commission recognized in the white paper, this is an area of concern, and both NIPSCO and NiSource believe this suggestion represents a fair allocation of costs and sends the proper price signal to the DG customer.

A consideration that could lower the monthly fixed charge portion is the ability of the utility to dispatch the DG unit. Differing rate structures could be used depending upon who dispatches the DG unit; however, in general, if the utility can dispatch the generation, it is worth more to the utility, and the utility should pay more for this ability.

Furthermore, if the Commission considers differing tariff structures for DG operators, including the ability of the utility to dispatch, the time of generation and use should be factored into any rate program so the market can give true market signals to the DG operators and utilities. For example, excess generation above the “ceiling level” will not always yield an avoided cost rate. The true value of power will deviate from this standard and could be worth more or less to the DG operator and utility, even zero at certain times of the day. This is true not only for the DG and utility relationship, but the electricity market as a whole.

However, when a tariff structure recognizes the true value of power beyond the "ceiling limit," then the DG unit should no longer have the ability to bank power on its meter from period to period, within a billing cycle, or even hour to hour. Banking power distorts the market signal to both the DG operator and utility because the utility's system observes shifts between its system's regions that are not captured when banking is allowed. This presents a ratepayer issue.

Recognizing this ratepayer issue, if the Commission elects to allow banking, both NIPSCO and NiSource would suggest designating this as a "pilot" program. Once DG displacement reaches a certain level, then the Commission and interested parties should be afforded an opportunity to re-evaluate the tariff structure. For example, one question that will need review at that point is whether or not the existing DG customers should be grandfathered under the old tariff structure or realize the same market signals as new entrants.

d. How should a utility determine the fixed amount of cost per customer with net metering, for both a net buyer and/or net seller?

The utility would use its latest cost of service study to determine the fixed cost portion, including margin, of its rate schedule used by the customer. Then it would have two options available depending upon the facility: (1) implement a monthly service charge to allow net metering, or (2) implement a transition surcharge on the basis of volume and this could be deducted from the avoided cost rate or it could be subtracted from the net excess energy produced by the customer.

As discussed above, NIPSCO and NiSource believe that implementing a monthly service charge for net metering reflects a reasonable solution to this issue. Once the costs are quantified, the DG customer should be responsible for the true fixed portion of being interconnected to the utility's system.

e. How do tariffs need to be designed to adequately reflect the efficient recovery of the fixed and variable costs for service to customers that operate DG equipment using a net meter?

As suggested through the monthly service charge, a flat fee could be charged in the way of a minimum bill amount. That amount will be equal to the fixed costs, return, and other costs associated with the recovery of the facilities used to connect the DG customer. All power up to the "ceiling level" that is sold to the utility would be at the full tariff rate. All power sold to the utility above the "ceiling level" could be purchased at the avoided cost rate, or a time of use adjusted rate, or some other rate that reflects actual value of the power.

NIPSCO and NiSource envision that DG customers of varying sizes will require different metering systems. Those DG customers that would require sophisticated metering should also realize an increase to their monthly service charge. This could be implemented through an additional "rental fee" for metering systems above normal, and this represents a fair allocation of costs to the DG customer. It is quite possible that differing customers will have differing monthly service charges.

Another suggestion for the Commission to consider is the idea that the utility could institute guaranteed revenue contracts into a minimum bill with new net metering customers the same way they do today for new customers. This would separate the incremental costs of the sophisticated metering system from the tariff structure and allow the parties to value the connection by itself. Additionally, NIPSCO and NiSource would suggest that it is possible for the utility to credit the DG customer through its monthly service charge. If the utility and the DG customer agree that the utility could dispatch the unit, then there is additional value realized by the utility. This could be implemented through a credit to the monthly service charge.

Regarding variable costs, simply having a monthly service charge will not likely cover all the stranded costs. There is still a portion of the demand-related charges that are left without responsibility. If the DG customer is willing to contract for standby power, then the utility needs the ability to allocate costs to that DG operator in the event that the utility is called upon to supply service. However, if the DG customer does not contract for standby power, then there are no demand-related costs left without responsibility.

In order to properly recognize the demand portion of the standby costs, the utility can use its cost of service structure to find the breaking point where a small versus a large DG unit needs to be responsible for demand-related costs. For example, the utility presumably knows at what load level customers need to begin paying for demand-related costs as opposed to purely energy-based. This model could be used to differentiate between the smaller and larger DG units that only reduce some of its load requirements versus total displacement. In addition, this alleviates any concerns that a very small generator should be paying demand-related costs. Once the utility identifies this demarcation and those DG operators that are responsible for demand-related costs, the utility could split the demand-related costs between the fixed-charge portion (*i.e.* the monthly service charge) and the energy-based charge when it actually uses the standby power. As further explained in question (i), the DG customer would see the energy charges plus the "penalty" portion that represents the demand-related costs. However, NIPSCO and NiSource again take this opportunity to stress that a "pilot" program is appropriate, and a review is necessary after the program reaches its stipulated limit.

f. How can stranded costs be identified and measured?

A number of techniques have been used by other states and suggested by commentators. These techniques attempt to determine the changed value of an asset in a competitive business environment as contrasted with a traditional regulated utility business environment. Any technique to deal with stranded costs needs to comply with applicable state law.

As reiterated above in question (e), there is a need for periodic review of the stranded cost situation within the "pilot" program because at some level of penetration, the load coming onto the system presents a different cost impact. At this point, NIPSCO and NiSource would not be able to identify if it is the 4th, 23d, or 115th customer. Thus, the answer cannot be determined at this point without moving forward and reviewing the situation as it progresses.

As far as recovery of quantified stranded costs, the utility could implement a transition surcharge, as highlighted in the Commission's white paper, either (1) during a stipulated period of time without review (similar to deregulation stranded cost Competitive Transition Charges in other states for the fixed charge portion), or (2) a mitigation pool is developed and the utility can credit these amounts against the pool for a defined period of time. The mitigation pool would include only the stranded cost dollars from those customers that elect to stay connected to the utility. If the utility is unable to recover the pool at the end of the period, all of the interested parties review the situation.

g. What, if any, are the benefits and revenues that should be considered as offsets to stranded costs?

There are benefits and revenues that should be considered as offsets to stranded costs. For example, avoided costs to the utility occur when the utility does not have to install new generation, power quality improvement corrections, or other system improvements. Another consideration is the reserve margin that the utility is required to maintain. Assuming that the DG penetration is recognizable to the system, the utility's expense of maintaining the specified reserve margin decreases. In some instances, DG may increase system reliability, reduce environmental emissions, and increase efficiency.

In terms of solely the DG customer, one of the benefits is that when the generation is located closer to the load, it inherently has less load and quality losses as compared to the traditional utility central station generators.

Lastly, a major benefit to utilities, DG developers, and ratepayers is that there is an enhanced matching of demand and supply growth. This promotes greater asset utilization and return on capital.

h. What rate design alternatives would reduce the potential for any stranded costs?

As NIPSCO and NiSource have mentioned before, DG power above the "ceiling level" should be priced at the price that reflects true market value for the commodity. If a utility is granted the ability to request a seasonal rate structure, then the utility would modify its avoided cost structure for excess generation from DG to reflect the value of time of year and even within a 24-hour period; however, if no authority for seasonal rate structure is granted, then the utility should keep the same price signals to the DG customers as it sees in the current flat rate structure.

If a true seasonal rate structure is not implemented, the Commission may want to consider a structure that would change the avoided cost rate based upon the season. For example, there could be two different avoided cost rate formulas; one during the summer months and one during the winter months. This would capture some of the price signal, including when the avoided cost rate is zero.

There are many potential stranded costs resulting simply from the displacement of the customer's existing load (*e.g.* reducing load from 60 KW to 30 KW), especially given that most fixed costs are currently recovered using a volumetric scheme. DG distorts the recovery of fixed charges through a volumetric rate design, so utilities should be afforded the opportunity to consider revising this design for DG purposes (please see questions (e) and (i) for further explanation).

i. Should standby rates for backup power be used, and if so under what criteria?

As NIPSCO and NiSource alluded to in question (e), if the DG customer connects to the electric utility with the expectation of service at any point, then standby rates should be used. Standby charges should be used; however, if the customer is responsible for a demand portion of the charge, this demand portion could be allocated between the fixed charge portion (*i.e.* monthly service charge) and the energy portion when the DG unit requires utility service. Therefore, there is no "demand charge" *per se* assessed to the DG operator, only a fixed charge portion on a billing cycle basis and then when it needs utility electric service, it is assessed a commodity charge plus a "penalty" portion. For those customers that are not responsible for a demand portion—see question (e)—the monthly service charge represents the true standby power portion.

The "penalty" portion would be an increment above the market cost for the energy. This would serve as an incentive for the DG operator to design its system to run continuously without needing service from the utility. However, NIPSCO and NiSource do recognize that there are DG systems like wind and solar, unless part of hybrid energy system, that may not be able to design their systems to run continuously.

j. What different kinds of standby services do customers with DG require and can the utility reasonably supply?

First, NIPSCO and NiSource believe it is important to differentiate a generic standby service from the list below. As discussed in question (i), there is a generic standby service that the DG customer needs when its own generation ceases. This is different than the specific services listed below because they are specifically requested and/or contracted for between the DG operator and utility. Therefore, the pricing methodology for generic standby services and specific services may be different.

There are different kinds of standby services that NIPSCO and NiSource can identify at the present; however, this list is not all inclusive. Some of the potential standby services include: (1) DG unit back up power, (2) maintenance power, (3) start-up power, (4) power quality support, (5) balancing, and (6) ancillary services.

Alternatively, there are services that the DG unit can provide to the utility, including many of the FERC Order No. 888 and 889 ancillary services. With that said though, if a generator (*e.g.* windmill customer) draws VARs off of the utility's system, then the customer should not be able to contract to sell VARs, but may actually need to pay for them when the market for VARs develops.

k. In order to determine the necessity and proper design of standby rates we need further information on distribution system design, operations, and cost structure. Please provide any information that might help to develop efficient standby rates.

NIPSCO and NiSource would suggest that the Commission rely on the utilities' cost of service studies. There is not an easily identifiable distinction between standby rates and the already quantifiable reserve for firm customers. The cost of service studies will illustrate the fixed charge portion, which is subsequently recovered through the volumetric portion of a customer's bill. This is the area where the Commission should consider revising the tariff structure if it is to provide incentives to DG. The fixed charge portions may adequately be recovered through the fixed charge on a customer's bill.

Some utilities, NIPSCO included, have already established standby rates in their tariff; however, the Commission must consider the ability for the utility to change this tariff once DG participation increases.

l. Are there areas in Indiana with distribution constraints?

Yes, there could be locations on the utility's system where DG is beneficial, but these areas are very site-specific. If the Commission considers these locations of benefit to DG growth, then NIPSCO and NiSource request that the Commission clarify what is meant by "distribution constraints." With this definition, it could be possible for utilities to develop three lists of areas within its territory that (1) definitely need attention, (2) could use attention, and (3) do not need attention for the construction of DG.

m. Should utilities be required to file a location-specific set of T&D costs?

NIPSCO and NiSource firmly believe that filing location-specific costs are unnecessary and would be burdensome. There is a difference between beneficial sites, as addressed in question (l), and costs of the system. To require location-specific costs would not provide any further incentives for DG operators, and it would also be a burden upon the utility and its ratepayers.

n. What constitutes an economically efficient buy-back rate?

An economically efficient buy-back rate is one that is based on open market pricing, including all costs needed to get the power to the load. The Commission's white paper presented this as an option, and an economically efficient buy-back rate sends the true market signals to both the utility and the DG operator. This includes periods where the DG unit is generating excess power where the power may actually be valued at zero.

NIPSCO and NiSource would also point out that buy-back rates are in fact an issue for small generators installed by a residential user. The Commission's white paper seems to regard this point as a non-issue for residential customers. Residential customers will, and in fact have, installed generators on their property that exceed their load up to 20 times. Therefore, this issue would apply and needs to apply to all DG operators.

o. What information should be included in a utility standard application form for distributed generation?

NIPSCO and NiSource submit that the following items should be included at a minimum: (1) location, (2) DG operator's timeframe for installation and start up, (3) number of units, (4) type of generator, (5) size of generator, (6) output voltage, (7) load stability, (8) load generation profile (*i.e.* windmill versus natural gas), (9) energy effectiveness, (10) does the DG operator wish the utility to have dispatch rights?, (11) is the generator inverter-based, and if so, what is the basic design criterion?, (12) if not inverter-based, what is the general design of the generator?, (13) does the system adhere to "pre-approved" or "pre-certified" standards including IEEE and UL?, and (14) does the system have an Uninterruptible Power Supply.

It is important to point out that having a "pre-approved" or "pre-certified" (*i.e.* IEEE) unit saves money for all ratepayers, utilities, and DG operators. Nonetheless, regardless if the DG unit is "pre-approved" or "pre-certified," the utility must always conduct a location study even though the generation unit has already been "pre-approved" or "pre-certified." In regard to the energy effectiveness item, there is a distinction between units that are "central station" in nature and those that are for the "public good." For example, there are units that have cogeneration uses and become an efficiency model.

p. What costs are incurred by a utility to review a DG project?

The utility incurs costs relating to the following: (1) interconnection review, (2) analyzing local effects to other customers and utility equipment, (3) existing utility equipment review to verify that the existing equipment can handle the new generation supplied from the DG unit to the utility, (4) system studies (under certain circumstances), (5) consideration of protective relaying and fusing schemes, and (6) if fuse saving practices are in place and if the presence of DG can influence recloser operation and hence the fusing scheme.

As NIPSCO and NiSource pointed out in question (o), some minimum review is required of the DG units' locations on the system; however, a "pre-approved" or "pre-certified" DG unit should not have the same cost and study requirements that apply to one that is not.

q. Do these costs vary for different DG project proposals?

The costs do vary for different DG projects. Some generation, such as wind and solar, generally have erratic load profiles. With these units the utility must review for peak and variable generation conditions to a different degree than those that have a more stable load profile. One of the items that vary is the review of the connection to make sure that it can handle the load variances. This differs from a CHP unit that would provide more of a base load profile.

The Commission should also recognize that reviewing the same DG unit might cost differently in two different locations on the utility's system. Furthermore, reviewing the DG unit may cost differently depending on the penetration level of DG onto the system or a specific feeder.

r. How long should it take a utility to evaluate a project?

The amount of time for a utility to evaluate a project depends upon the unit's size, type, and location. For units above 100 KW in size, this may necessitate a different cost schedule and timeline than units below this level. Nonetheless, the initial system impact study for units below 100 KW should normally not extend beyond 30 days for "pre-approved" or "pre-certified" units; however, there may be unusual circumstances that may extend the period of review. This initial system impact study will provide the DG customer with a definite "yes" or "no" answer regarding its request for interconnection. If the answer is "no," then the DG operator and utility shall put forth a "good faith" effort to resolve the outstanding issues that resulted in the "no" answer.

Once the initial system impact study is complete, the utility and DG operator should stipulate "good faith" timeframes.

s. What are the criteria a utility should use to evaluate a DG project?

The utility needs to consider the following: (1) a system impact study including the DG unit's location on a specific feeder and subsequent testing of that feeder with the DG unit, (2) the fixed cost component of the utility equipment affected, (3) is the generation dependable?, (4) when is the generation most likely available?, (5) is the generation dispatchable by the utility?, (6) indemnity, (7) "pilot" review level, and (8) penetration level on the feeder for issues of voltage (fault-related) and local stability (15% per feeder).

Whether or not the generation is dispatchable by the utility or if it is dependable or available are factors for the DG operator and the utility to consider for business opportunities; however, the DG operator has the ability to decline business opportunities with the utility and elect the shortest review path.

Lastly, the utility must have tariff or contract language in place that would provide it the right to prove that a system problem was not its fault, but may have been the DG unit's fault; therefore, the cost responsibility shifts to the responsible party.

t. To what extent should DG be required to be included in the IRP evaluation process? Should utilities be required to post where on their systems DG would be of most economic benefit?

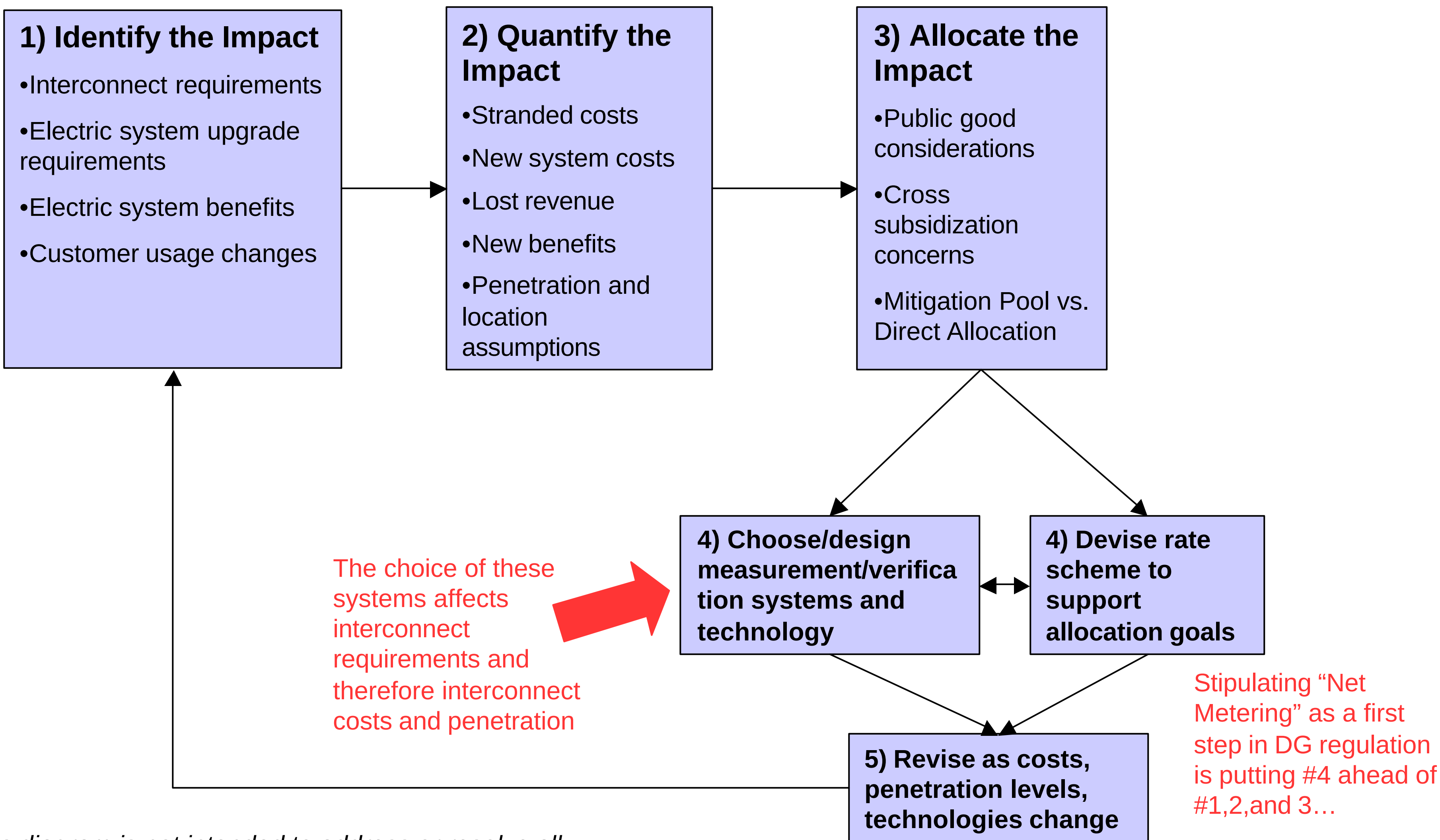
Due to the early stages of DG and how it can be deployed or encouraged by utilities as an alternative technique to upgrade T&D lines or provide additional power, the Commission should encourage, but not require utilities to include DG in the IRP evaluation process. The Commission should continue to seek additional comments on where utilities can use DG as an alternative methodology to increase reliability and/or supply.

u. Expedited procedures and cost for impact studies for small generators.

A utility must always review a request for interconnection. "Plug and play" is an inappropriate term, and the utility must always be involved to some extent. Some parties have argued in the past that the DG industry will eventually mature to the point where small generators will not need utility review. NIPSCO and NiSource support expedited procedures for small generators, reduced time and costs where units are "pre-approved" or "pre-certified," and a cost structure that is fair to both the DG operator and the utility. However, DG units will always need some minimum review, and NIPSCO and NiSource believe this point is necessary to convey to the Commission that some minimum review is in fact required.

Exhibit 1

Developing Distributed Generation: The Regulatory Process



This diagram is not intended to address or resolve all issues, but to present their relationship.